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Boiler Design Criteria for Dry Sorbent SO2 Control with Low-NOx Burners New Unit Applications

Combustion Engineering, Inc., Windsor, CT

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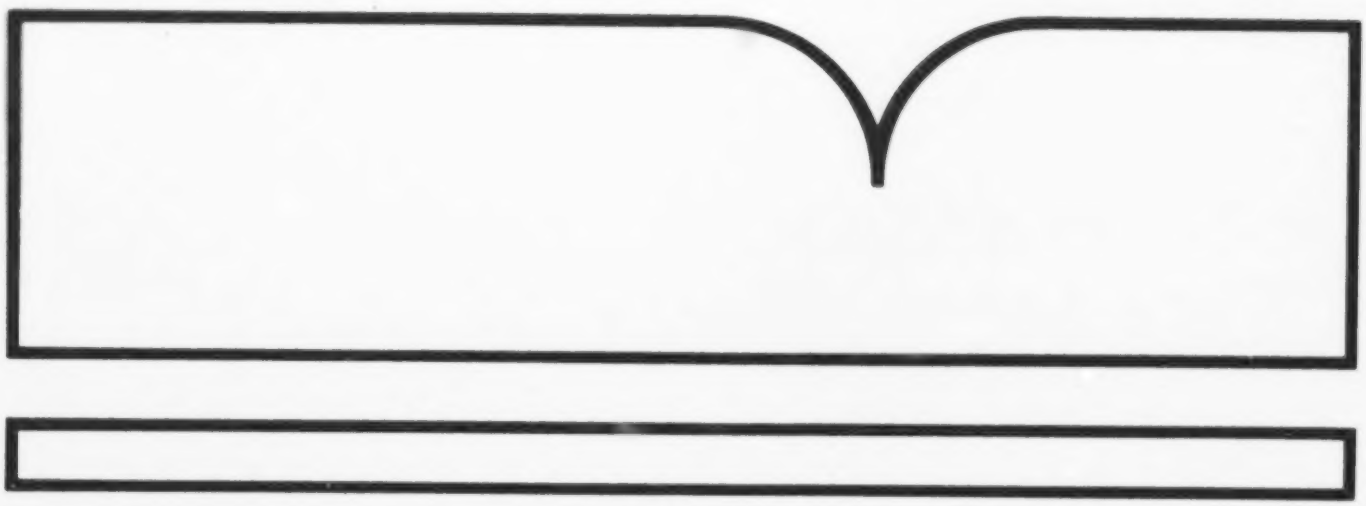

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BOILER DESIGN CRITERIA FOR DRY SORBENT SO_2 CONTROL WITH LOW-NOx BURNERS: NEW UNIT APPLICATIONS

By

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EPA Contract 68-02-3915

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Sulfur Oxides	Burners	Stationary Sources	07B
Sorbents	Coal	Dry Sorbents	11G 21D
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ABSTRACT

A study to define the boiler modifications required to achieve 70% SO_2 removal with sorbent injection on a large tangentially-fired utility boiler without supplemental spray drying was conducted under EPA sponsorship. This task was executed as a follow-on to a recently completed broader evaluation of boiler design criteria for sorbent SO_2 control technology. A new 500 MWe utility boiler burning low-sulfur coal was considered to be modified to increase sorbent residence time and decrease gas quench rate to achieve 70% SO_2 removal in the boiler with atmospheric calcium hydrate prepared on-site. A second case was considered where no change was made to gas quench rate or sorbent residence time. The effects of adding a pulverizer to the sorbent preparation/injection system to permit production of a finer sorbent were determined. Capital costs, cost of electricity, and cost effectiveness per ton of SO_2 removed were developed and compared with the results of the earlier study.

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SECTION 1

INTRODUCTION

This report presents results of additional work carried out under EPA Contract 68-02-3915. Among the cases studied in the initial study, the costs associated with incorporating sorbent injection on new low-sulfur (0.55% S) units (200 MWe, 400 MWe, and 600 MWe) were determined. A 50% SO_2 reduction in the boiler alone, using pulverized limestone as the sorbent, was assumed. Overall SO_2 removal of 70% (NSPS requirement) was achieved by incorporating a spray dryer. Boiler modifications to accommodate sorbent injection were limited to convective surfaces and enhanced sootblower capability. No changes to the boiler evaporative surfaces were made. The results of these analyses were presented in the project Final Report, Ref. (1).

The objective of the follow-on study was to determine the relative cost of designing for New Source Performance Standards SO_2 compliance (70% SO_2 removal), using only sorbent injection, on a new 500 MWe tangentially-fired utility unit burning low-sulfur coal.

SECTION 2

CONCLUSIONS

The results of the initial study, Ref. (1), showed that the combination of limestone sorbent injection plus a spray dryer offered significant cost advantages over conventional flue gas desulfurization for achieving 70% SO_2 removal on new low-sulfur tangentially-fired utility boilers. This study was predicated on 50% SO_2 reduction in the boiler and the remaining reduction in the spray dryer.

The results of this follow-on study show that additional substantial reductions in the cost of achieving NSPS SO_2 compliance on new tangentially-fired low-sulfur coal-burning utility boilers using sorbent injection can be realized by modifying the conventional boiler design to obtain low gas quench rates (<400°F/sec)* through the critical 2250°F to 1600°F sulfation window.

For the extensively modified boiler design, incorporation of sorbent injection using $Ca(OH)_2$ to achieve 70% SO_2 reduction in the boiler costs 18.45 $/kW. First-year cost effectiveness of SO_2 removal was 574.32 $/ton (30-year levelized cost effectiveness was 1103.26 $/ton). First-year incremental cost of electricity was 1.66 mills/kW-hr (30-year levelized cost was 3.19 mills/kW-hr). From the initial study, Ref. (1), the cost of incorporating sorbent injection (limestone) plus a spray dryer to achieve 70% SO_2 reduction on a new 600 MWe low-sulfur unit was 44.10 $/kW. First-year effectiveness of SO_2 removed was 788.98 $/ton (30-year levelized cost effectiveness was 1287.90 $/ton). First-year incremental cost of electricity was 2.29 mills/kW-hr (30-year levelized cost was 3.73 mills/kW-hr).

Incorporation of sorbent injection to achieve 70% SO_2 removal on a new 500 MWe low-sulfur unit with minimal modifications (no cavities) resulted

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(*) Readers more familiar with metric units may use the conversion factors tabulated at the end of this report.

in a slightly lower capital cost (17.24 $/kW) than the unit with cavities, but a higher (poorer) first-year cost effectiveness of SO_2 removed (603.24 $/ton) (30-year levelized cost effectiveness was 1184.91 $/ton). First-year incremental cost of electricity was 1.74 mills/kW-hr (30-year levelized cost was 3.42 mills/kW-hr).

Adding a pulverizer to the sorbent preparation/injection system to achieve a finer sorbent product added 2.87 $/kW to the overall cost for either boiler design.

SECTION 3

PROCESS DESCRIPTION

The initial work performed under this contract (EPA-68-02-3915) was predicated on the use of limestone ($CaCO_3$) as the sorbent material. The overriding reason for selecting limestone was the relative cost of the sorbent material. While the SO_2 removal performance of atmospheric hydrated lime ($Ca(OH)_2$) has been consistently demonstrated to be far superior to that of pulverized limestone, the low cost and high availability of limestone has given it a perceived advantage in boiler sorbent injection application studies. In order to achieve the levels of SO_2 removal consistent with New Source Performance Standards for new utility boilers burning low-sulfur coal (70% SO_2 removal) at reasonable Ca/S molar ratios, it is necessary to use a higher reactivity sorbent such as $Ca(OH)_2$. This is shown in Figure 1, which presents the relative SO_2 capture performance of $CaCO_3$ and $Ca(OH)_2$ over a range of Ca/S molar ratios for low (300°F/sec) and intermediate (700°F/sec) gas quench rates. These data, obtained from EPA, represent a composite of laboratory- and pilot-scale data from various sources. It can be seen that limestone cannot achieve 70% SO_2 removal, even at high Ca/S molar ratios and low gas quench rates. For new units burning low-sulfur coal, incorporating furnace sorbent injection for SO_2 control using limestone as the sorbent material would require supplementary SO_2 control equipment, such as spray dryers, to achieve an overall SO_2 removal of 70%. (This approach was used in the initial study under this contract, Ref. (1).)

3.1 Sorbent Preparation and Delivery

Continuous production of adequate quantities of atmospheric $Ca(OH)_2$ is a relatively straightforward process using conventional commercially available equipment. A general schematic flowsheet for a typical lime hydrating plant is shown in Figure 2. This plant produces 10 μm to 20 μm average particle size hydrate from 1/2"x0 quicklime feed. If a finer product is required, additional pulverizing can be carried out, as shown in

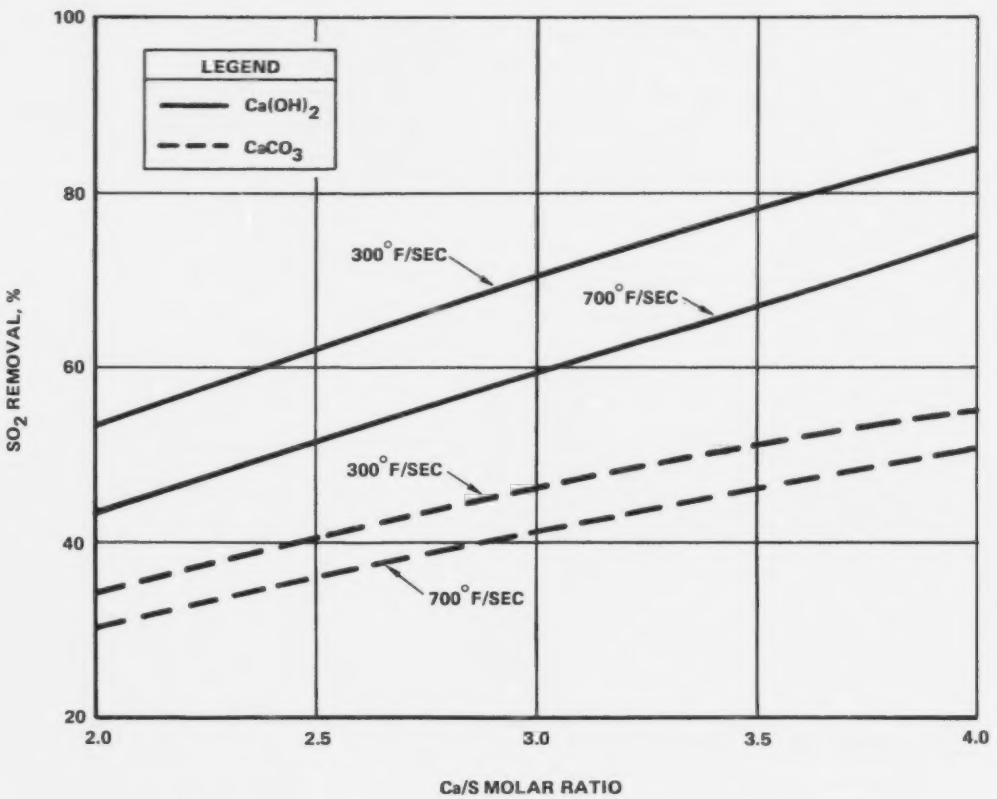

Figure 1. Expected SO_2 capture performance for limestone and calcium hydrate as a function of gas quench rate through the 2250°F to 1600°F region.

Figure 2. Both configurations were considered in this study. (Note: A C-E Raymond roller mill was substituted for the ball mill shown in Figure 2.) Both the quicklime feed and the hydrate product materials were assumed to be 95% pure (5% inerts).

The hydrating plant specified for this study is capable of producing a continuous supply of sorbent at the rate of 10 tons per hour. The plant is supplied from an unloading/transport system capable of handling 30 tons per hour, based on conventional practice of operating this equipment for one shift per day. Since quicklime is very reactive when exposed to water, both the unloading/transport and hydrating systems are under cover.

From the hydrate bin, the material is transported pneumatically to injection ports located in the front wall region of the boiler. The sorbent material is fed by a rotary valve to a venturi where it is entrained in the transport air stream. As in the initial study, dilute-phase transport at an air-to-solids ratio of 1.5 is used. The delivery line splits twice, supplying the sorbent material to four (4) locations in the convective section of the boiler.

3.2 Boiler Design Considerations

A side elevation drawing of the baseline unit selected for this study is shown in Figure 3. The performance of this unit, rated at 500 MWe, was determined based on the same low-sulfur coal used in the initial study under this contract. The as-received analysis of this coal is shown in Table 1. Figure 3 has been simplified to show only those dimensions which relate to the current study.

The time/temperature history plot for this unit is shown in Figure 4. The quench rate through the critical 2250°F to 1600°F sulfation window was calculated to be 591°F/sec. Based upon the sorbent performance information from EPA which was used to generate Figure 1, a Ca/S molar ratio of 3.5:1 was selected to achieve 70% SO_2 removal at this quench rate. It was decided to assure at least 1.5 seconds residence time through the critical sulfation window. To achieve this, the quench rate would have to be

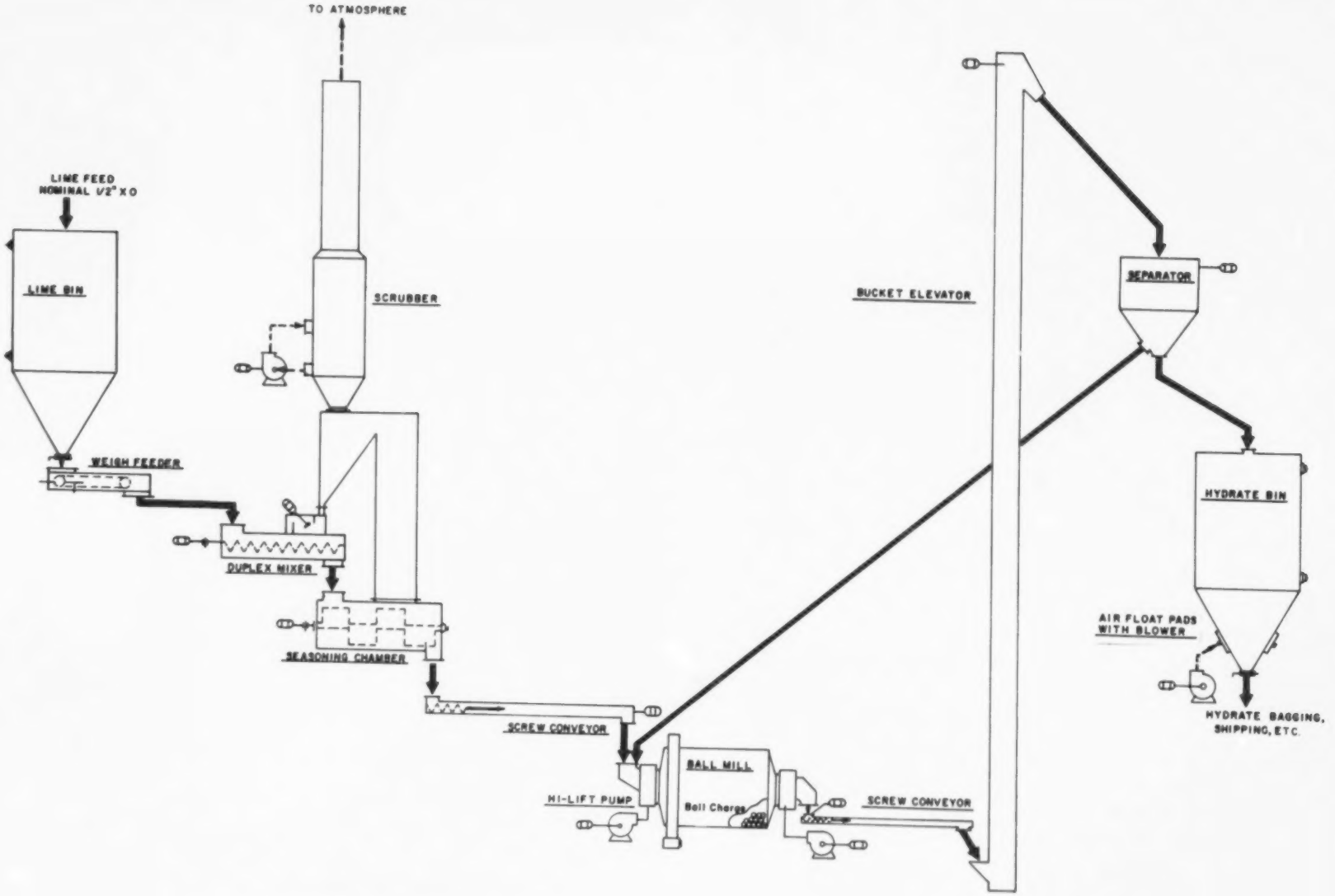

Figure 2. Typical flowsheet of a lime hydrating plant (Ref. 2).

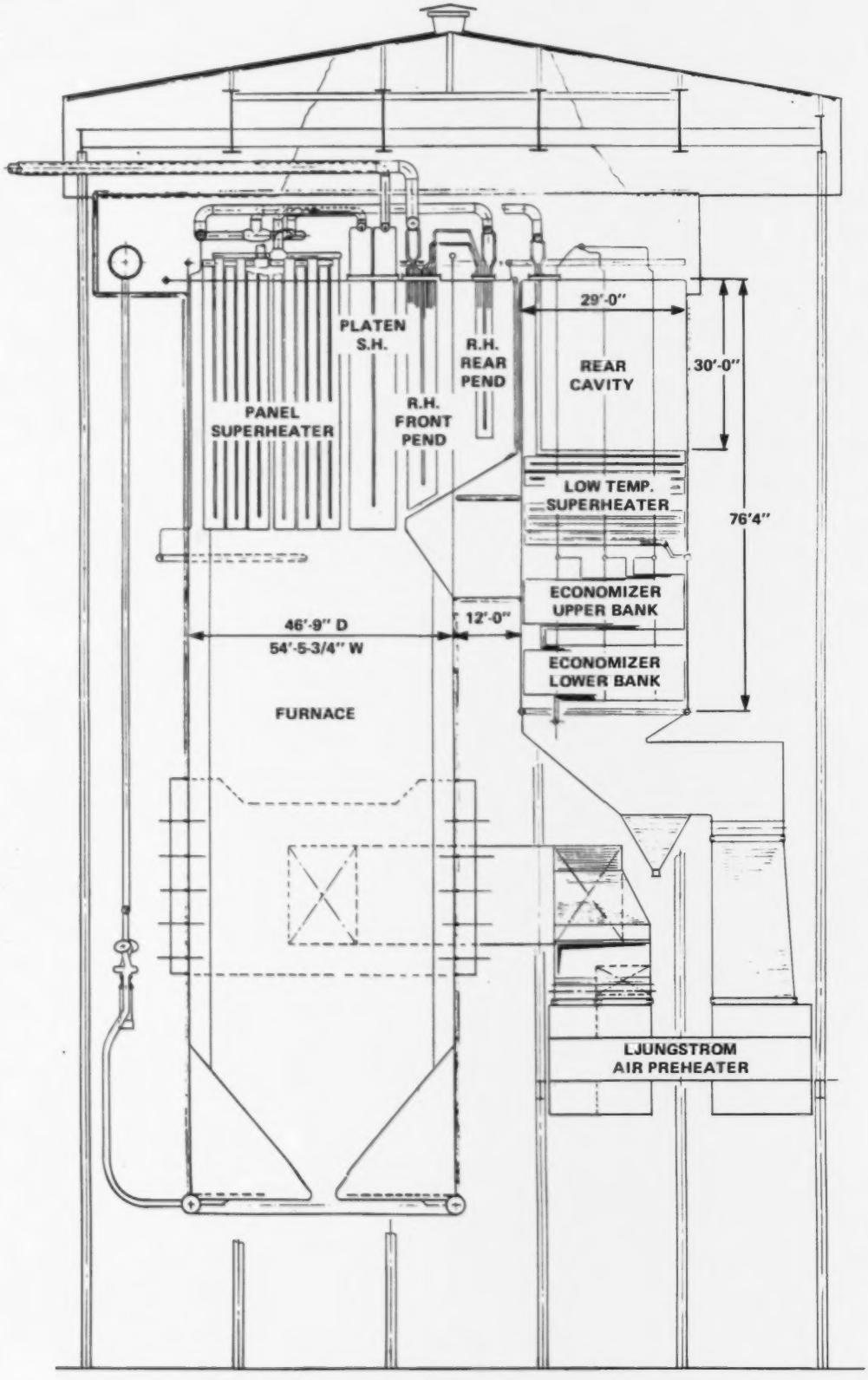

Figure 3. Side elevation of 500 MWe base unit.

TABLE 1: AS-RECEIVED COAL ANALYSIS

Proximate Analysis, Wt %	
Moisture	6.43
Volatile Matter	40.67
Fixed Carbon	44.08
Ash	8.82
Ultimate Analysis, Wt %	
Moisture	6.43
Carbon	68.30
Hydrogen	4.91
Nitrogen	0.81
Sulfur	0.55
Oxygen	10.18
Ash	8.82
HHV, Btu/lb (as-received)	12,192
Ash Analysis, Wt %	
SiO_2 (silica)	52.70
Fe_2O_3 (ferric oxide)	9.88
Al_2O_3 (alumina)	17.63
TiO_2 (titanium oxide)	1.45
CaO (calcium oxide)	9.69
MgO (magnesia)	1.84
SO_3 (sulfur trioxide)	0.71
K_2O (potassium oxide)	0.66
Na_2O (sodium oxide)	1.33
P_2O_5 (phosphorous pentoxide)	N/A
Undetermined	4.11
TOTAL	100.00

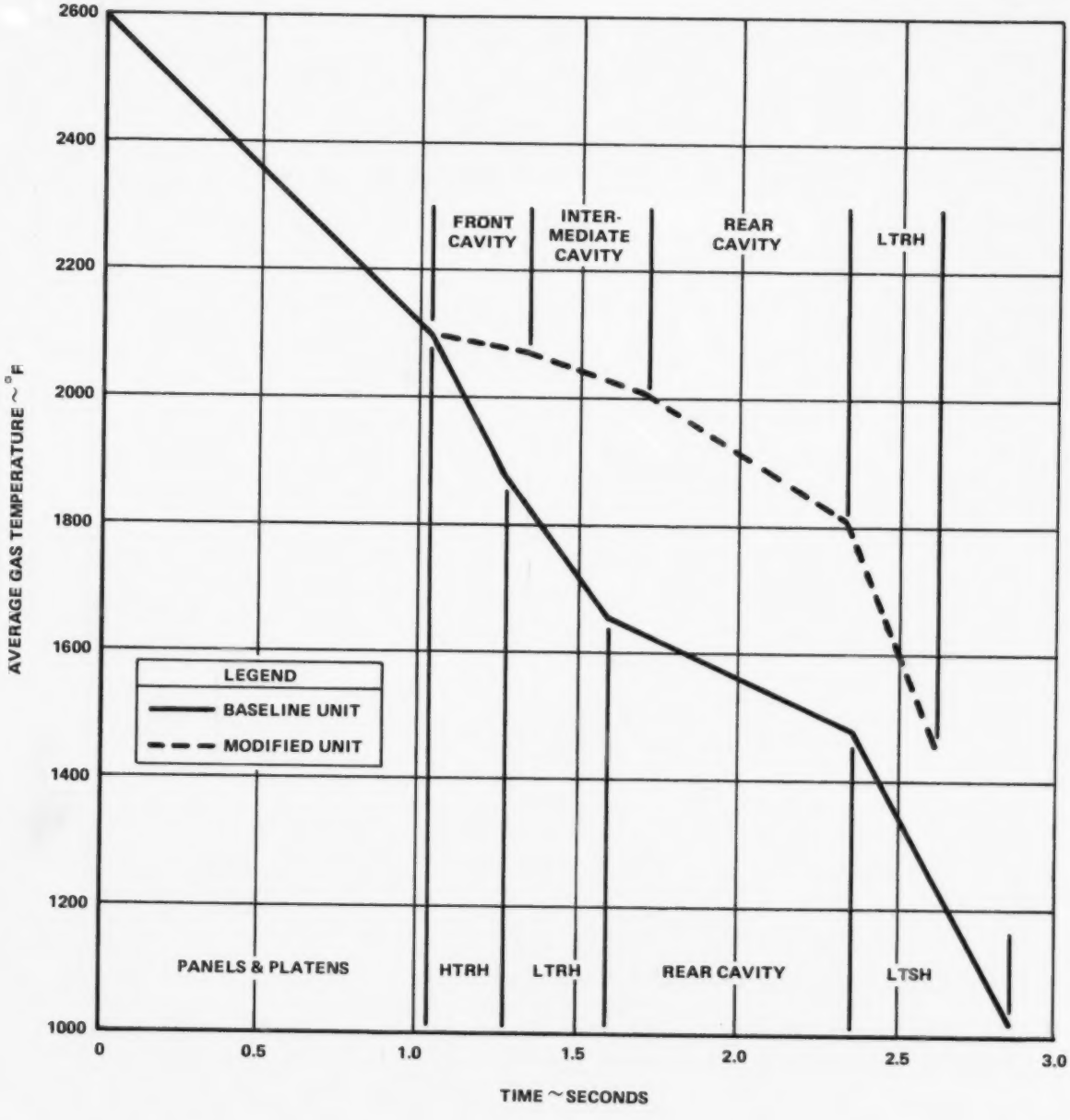

Figure 4. Time/temperature plot for base and modified units.

reduced, thus reducing the required Ca/S molar ratio (Note from Figure 1 that a reduction in quench rate to 300°F/sec from 700°F/sec results in a substantial reduction in Ca/S molar ratio to 3.1:1 from 3.7:1).

Analysis of the performance of the baseline design determined that the most effective approach for achieving a significant increase in gas residence time (reduction in quench rate) was to incorporate additional open cavity sections in the convective pass and relocate the original reheat surface to the rear pass area. It was decided to place the cavity sections immediately following the platen superheater section. While there is a significant bottom-to-top temperature gradient at this point, the average gas temperature of 2100°F is well within the optimum sulfation window. A side elevation for the unit as modified for sorbent injection is shown in Figure 5.

Three major modifications which were made to the baseline unit to make it suitable for furnace sorbent injection can be seen by comparing Figures 3 and 5. By moving the reheat surface to the rear pass section, the front and intermediate open cavity sections were created. A portion of the intermediate cavity was created by increasing the space between the furnace and the rear pass section. By moving the reheat surface to the rear pass and adding the open cavity sections in the convective pass, the temperature leaving the rear cavity was increased 330°F. The time/temperature history plot for this unit is shown in Figure 4. The quench rate was reduced to 360°F/sec from 591°F/sec, thus reducing the required sorbent stoichiometry to 3.1:1 from 3.5:1.

The rear pass required lengthening by just over 23 ft. This reflected the combined effects of two design sorbent injection-related modifications: the relocation of the reheat surface to the rear pass, and modifications to the arrangements of the rear pass sections to reduce gas velocities through those sections. The reheat pendant sections were relocated to the upper rear pass area as horizontal sections (upper and lower banks). This move, together with limitations in allowable gas velocities (less than 60 ft/sec to minimize the potential for tube erosion), resulted in a change in the selected tube material and an increase in the transverse spacing for the

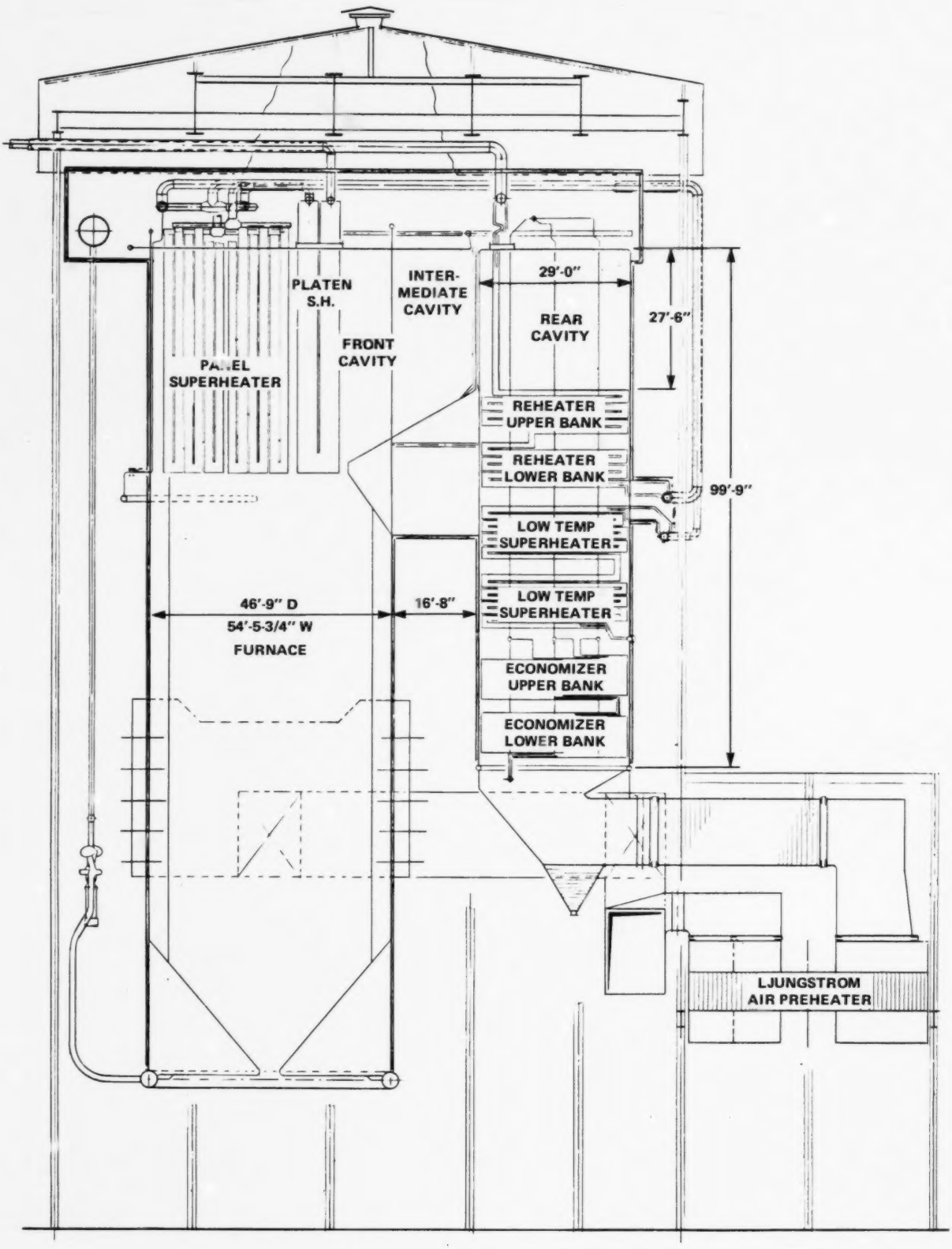

Figure 5. Side elevation of 500 MWe unit with modifications to achieve 70% SO_2 reduction with sorbent injection.

TABLE 2: CONVECTIVE SURFACE ARRANGEMENT DATA (page 1 of 3)[1]

A. BASE UNIT (No Sorbent)

	Section	No. Assys.	No. Elem.	No. Loops	S_T	S_L	Tube O.D.	Lin. Ft.	Devel. Ft^2	Projected Ft^2
1.	SH Panels	12	396	1	93"	2-1/8"	1-3/4"	28,484	-	12,060
2.	SH Platens	26	572	1	25"	2-1/4"	1-7/8"	48,120	-	18,045
3.	HTRH Pendant	64	512	1	10"	4-1/2"	2-1/8"	39,766	22,110	
4.	LTRH Pendant	128	512	1	5"	4-1/2"	2-1/8"	27,739	15,423	
5.	LTSH Terminals	144	576	1/2	4-1/2"	4"	2"	17,304	9,050	
6.	LTSH Horizontal	144	576	2 Banks 2-3/4 Loops per Bank	4-1/2"	4"	2"	180,906	94,614	
7.	Economizer Hangers	71	213	-	9"	-	2"	10,558	5,522	(Total)
8.	Economizer (Bare Tube)	162	486	2 Banks 109 Rows High	4"	4"	2"	275,092	143,873	

Note: 1. See glossary for explanation of terms.

TABLE 2: CONVECTIVE SURFACE ARRANGEMENT DATA (page 2 of 3)[1]

B. SORBENT BOILER (With Cavities)

	Section	No. Assys.	No. Elem.	No. Loops	S_T	S_L	Tube O.D.	Lin. Ft.	Devel. Ft^2	Projected Ft^2
1.	SH Panels	← SAME AS BASE UNIT →								
2.	SH Platens	← SAME AS BASE UNIT →								
3.	Reheat Terminals	64	256	-	10"	4-1/2"	2-1/4"	7,037	4,145	
4.	HTRH Horiz. (Upper Bank)	64	256	2-3/4	10"	4-1/2"	2-1/4"	78,278	46,106	
5.	LTRH Horiz. (Lower Bank)	64	256	2-3/4	10"	4-1/2"	2-1/4"			
6.	LTSH Horiz.	128	512	2 Banks 4 Loops per Bank	5"	4"	2"	225,172	117,765	
7.	Economizer Hangers	64	192	-	10"	-	2"	14,507	7,587	
8.	Economizer (Bare Tube)	162	486	2 Banks 106 Rows High	4"	4"	2"	243,254	127,222	

Note: 1. See glossary for ex lanation of terms.

TABLE 2: CONVECTIVE SURFACE ARRANGEMENT DATA (page 3 of 3)[1]

C. BASE UNIT WITH WIDE LANE REHEATER & LTSH (No Cavities)

	Section	No. Assys.	No. Elem.	No. Loops	S_T	S_L	Tube O.D.	Lin. Ft.	Devel. Ft^2	Projected Ft^2
1.	SH Panels	← SAME AS BASE UNIT →								
2.	SH Platens	← SAME AS BASE UNIT →								
3.	HTRH Pendant	64	512	1	10"	4-1/2"	2-1/8"	39,766	22,110	
4.	LTRH Pendant	64	512	1	10"	4-1/2"	2-1/8"	29,718	16,523	
5.	LTSH Terminals	128	512	1/2	5"	4"	2"	15,501	8,107	
6.	LTSH Horizontal	128	512	Upper $2\frac{3}{4}$ Lower $3\frac{3}{4}$	5"	4"	2"	190,138	99,442	
7.	Economizer Hangers	71	213		10"	-	2"	11,126	5,819	(Total)
8.	Economizer	162	486	109 Rows High	4"	4"	2"	276,140	144,421	

Note: 1. See glossary for explanation of terms.

lower bank. A slight increase in transverse spacing was also made for the horizontal low temperature superheater. Changes in heat transfer surface were required for the low temperature reheat, low temperature superheat, and economizer sections. Table 2 summarizes the surface changes made to the baseline unit design in conjunction with incorporation of the front and intermediate cavities. In addition, due to space limitations which resulted from lengthening the rear pass, it was necessary to reposition the Ljungstrom air heater, as can be seen by comparing Figures 3 and 5.

For purposes of comparison, an alternate case was examined in which no cavities were incorporated in the base unit. This case was intended as a trade-off study, where the capital costs associated with boiler modifications would be reduced, but the operating costs associated with the required sorbent stoichiometry (3.5:1 vs. 3.1:1 for the modified unit) would be greater. The original convective and rear pass configurations were retained. Transverse spacing for the low temperature superheat sections was increased to minimize the potential for tube erosion. The time/temperature characteristics and quench rate were essentially unchanged from the original base unit. The surface requirements for this modified base unit changed slightly as shown in Table 2. The effect on the rear pass due to these changes was minimal, resulting in an increase of less than 3 ft. No change in the location of the Ljungstrom air heater was required.

Sootblowing capabilities were increased for both sorbent injection boilers to an extent consistent with the upgrades made to new low-sulfur units in the original study (24 additional retractable blowers and 4 additional wall blowers).

3.3. Back End Modifications

The only modification which was required for either sorbent injection-equipped boiler was an increase in the capabilities of the ash handling equipment. It was assumed that a baghouse was used for particulate collection. As in the initial study under this contract, Ref. (1), the size and cost of the baghouse was assumed to be independent of the sorbent-related material, and, therefore, no change in capacity or cost

resulted from incorporating sorbent injection. Removal of the increased amount of collected solids, however, required an upgrade to the base ash handling system. Only the incremental cost associated with the sorbent-related upgrade was included in the economic analyses.

SECTION 4

ECONOMIC ANALYSIS

Total costs which were developed for the sorbent injection-modified units are presented in this section. Costs were developed for two boiler designs: one with open cavities in the convective pass area for increased sorbent residence time, and one with only minor surface modifications to the base unit. In addition, the effect on process economics of incorporating a pulverizer in the sorbent preparation system was considered for each boiler configuration. The EPRI format as outlined in the Technical Assessment Guide (TAG) was used. Specific assumptions for individual cost items were arrived at after discussion with the EPA Project Officer.

4.1 Economic Premises

For a detailed discussion of the economic premises used in arriving at the process costs, refer to Section 11 of the Final Report on the initial study under this contract, Ref. (1). All assumptions made for the initial study were retained for the current study with the following exception: for the original study, limestone at $17.88/ton was the sorbent used; for the current study, quicklime at $70/ton was used as the feed to the $Ca(OH)_2$ preparation system ($43/ton represents material cost, FOB works; the balance of the $70/ton cost represents transportation to the power plant).

4.2 Economic Analyses

The economic analyses were carried out as outlined in Subsection 11.1 of Ref. (1). Costs were developed on a $/kW, $/ton SO_2 removed, and mills/kW-hr basis, both first year and levelized. For both modified boiler cases, the costs were developed with and without a pulverizer incorporated in the sorbent preparation (hydrating) system to provide a measure of how much this option would add to the process cost, should increased sorbent fineness be required.

The results of these analyses are presented in Tables 3 through 6. The incremental in-plant power requirements used in determining the in-plant power costs are presented in Table 7.

Table 8 presents a breakdown of the Process Capital Costs into sorbent preparation/injection costs, boiler modification costs, and back-end equipment (ash handling) costs. Table 9 presents a breakdown of the sorbent preparation and injection costs for the basic hydration process, including the quicklime unloading and handling equipment. Table 10 presents the costs associated with incorporating a pulverizer at the outlet of the hydrating system to produce a finer sorbent product. Table 11 presents a breakdown of the boiler modification costs into surface modifications and increased sootblower capacity costs.

4.2.1. Modified Base Unit with Cavities

For the modified boiler design in which cavities were incorporated to increase sorbent residence time and reduce gas quench rate:

- The cost of incorporating sorbent injection using atmospheric $Ca(OH)_2$ to achieve 70% SO_2 removal in the boiler was 18.45 $/kW. The first-year cost effectiveness of SO_2 removed was 574.32 $/ton (30-year levelized cost effectiveness was 1103.26 $/ton). The effect on first-year cost of electricity of incorporating the boiler modifications, hydrating system, and ash handling upgrade was 1.66 mills/kW-hr (30-year levelized cost was 3.19 mills/kW-hr).

- The cost of adding a pulverizer to the sorbent preparation/injection system to achieve a finer sorbent product was 2.86 $/kW. The first-year cost effectiveness of SO_2 removed was poorer, increasing to 615.27 $/ton from 574.32 $/ton (30-year levelized cost effectiveness was 1162.92 $/ton). The first-year cost of electricity increased to 1.78 mills/kW-hr (30-year levelized cost was 3.36 mills/kW-hr).

From Ref. (1), the cost of incorporating sorbent injection on a new 600 MWe low-sulfur unit using pulverized limestone to achieve 50% SO_2 reduction in the boiler and a spray dryer to achieve 70% overall SO_2 reduction was 44.10 $/kW. First-year cost effectiveness of SO_2 removed was 788.98 $/ton (30-year levelized cost effectiveness was 1287.90 $/ton). First-year cost of electricity was 2.29 mills/kW-hr (30-year levelized cost was 3.73 mills/kW-hr). Thus, modifying the boiler to achieve 70% with sorbent injection alone, plus switching from pulverized limestone to atmospheric hydrate produced on-site, reduced the sorbent injection-related capital costs by over 58% and the SO_2 removal effectiveness costs and cost of electricity by over 27%. Incorporating a pulverizer in the sorbent preparation/injection system reduced these improvements to more than 51% for capital costs and more than 22% for SO_2 removal effectiveness costs and cost of electricity.

4.2.2 Modified Base Unit without Cavities

For the modified boiler design in which only the convective section arrangement (spacing) was modified, without creating new open cavities:

- The cost of incorporating sorbent injection using atmospheric $Ca(OH)_2$ to achieve 70% SO_2 removal in the boiler was 17.24 $/kW, compared with 18.45 $/kW for the unit with cavities. The first-year cost effectiveness of SO_2 removed was 603.24 $/ton, compared with 574.32 $/ton for the unit with cavities, which demonstrates the effect of the higher Ca/S molar ratio required for this higher quench rate unit (30-year levelized cost effectiveness for this unit was 1184.91 $/ton). The first-year cost of electricity was 1.74 mills/kW-hr (30-year levelized cost was 3.42 mills/kW-hr). This compares with 1.66 mills/kW-hr and 3.19 mills/kW-hr, respectively, for the unit with cavities.

- The cost of adding a pulverizer to the sorbent preparation/injection system to achieve a finer sorbent product was 2.87 $/kW. The first-year cost effectiveness of SO_2 removed was poorer, increasing to 644.22 $/ton from 603.24 $/ton (30-year levelized cost effectiveness for this unit was 1244.59 $/ton). The first-year cost of electricity increased to 1.86 mills/kW-hr (30-year levelized cost was 3.59 mills/kW-hr).

TABLE 3: ECONOMIC ANALYSIS OF
500 MWE NEW LOW-SULFUR UNIT MODIFIED FOR
SORBENT INJECTION, WITH CAVITIES (NO MILL)[1]

Capital Investment	10^3 $	$/kW
Process Capital	4089.9	8.18
General Facilities	204.5	0.41
Engineering and Home Office Fees	409.0	0.82
Project Contingency	818.0	1.64
Process Contingency	409.0	0.82
Total Plant Cost (Dec. 1985 dollars)	5930.4	11.87
Total Plant Investment (Jan. 1986 startup)	5930.4	11.87
Preproduction Costs	2692.1	5.38
Inventory Capital	601.2	1.20
Total Capital Requirement (Jan. 1986 startup)	9223.7	18.45

Operating and Maintenance Costs (First Year - Dec. 1985 dollars)	10^3 $	$/kW-yr
Operating Labor	307.1	0.61
Maintenance Labor	65.4	0.13
Maintenance Materials	98.2	0.20
Administrative and Support Labor	111.8	0.22
Total O&M First Year	582.5	1.16
Fixed O&M First Year	378.6	0.76
Variable O&M First Year	203.9	0.07 mills/kW-hr

Consumables Operating Costs Excluding Fuel (First Year - Dec. 1985 dollars)	10^3 $	mills/kW-hr
Lime	2341.4	0.82
In-Plant Power (140.5 kW)	46.4	0.02
Other Consumables: Water	1.9	0.00
Waste Disposal	337.0	0.12
Total Consumables (excluding fuel)	2726.7	0.96

	10^3 $	
Fuel Cost (Increment) (First Year - Dec. 1985 dollars)	0.0	0.00 mills/kW-hr
Carrying Charges (First Year - Dec. 1985 dollars)	1412.1	2.82 $/kW-yr
Busbar Cost of Power (First Year - Dec. 1985 dollars)	4721.3	1.66 mills/kW-hr
First Year Cost Effectiveness SO_2 Removed	4721.3	574.32 $/ton
30-Year Levelized O&M Costs	**10^3 $**	
30-Year Levelized Fixed O&M	876.1	1.76 $/kW-yr
30-Year Levelized Variable O&M	471.8	0.17 mills/kW-hr
30-Year Levelized Consumables O&M	6309.6	2.22 mills/kW-hr
30-Year Levelized Carrying Charges	1412.1	2.82 $/kW-yr
30-Year Levelized Busbar Cost of Power at Levelized Capacity Factor (0.65)	9069.6	3.19 mills/kW-hr
30-Year Levelized Cost Effectiveness SO_2 Removed	9069.6	1103.26 $/ton

Note: (1) Coal Sulfur Content: 0.55 %
Calcium/Sulfur Mole Ratio: 3.1:1
SO_2 Removed in Boiler: 70 %
Overall SO_2 Removal: 70 %

TABLE 4: ECONOMIC ANALYSIS OF
500 MWE NEW LOW-SULFUR UNIT MODIFIED FOR
SORBENT INJECTION, NO CAVITIES (NO MILL)[1]

Capital Investment	10^3 $	$/kW
Process Capital	3606.2	7.21
General Facilities	180.3	0.36
Engineering and Home Office Fees	360.6	0.72
Project Contingency	721.2	1.44
Process Contingency	360.6	0.72
Total Plant Cost (Dec. 1985 dollars)	5228.9	10.45
Total Plant Investment (Jan. 1986 startup)	5228.9	10.45
Preproduction Costs	2715.0	5.43
Inventory Capital	678.7	1.36
Total Capital Requirement (Jan. 1986 startup)	8622.6	17.24

Operating and Maintenance Costs (First Year - Dec. 1985 dollars)	10^3 $	$/kW-yr
Operating Labor	307.1	0.61
Maintenance Labor	57.7	0.12
Maintenance Materials	86.5	0.17
Administrative and Support Labor	109.4	0.22
Total O&M First Year	560.7	1.12
Fixed O&M First Year	364.5	0.73
Variable O&M First Year	196.2	0.07 mills/kW-hr

Consumables Operating Costs Excluding Fuel (First Year - Dec. 1985 dollars)	10^3 $	mills/kW-hr
Lime	2643.6	0.93
In-Plant Power (140.5 kW)	46.4	0.02
Other Consumables: Water	2.1	0.00
Waste Disposal	386.2	0.14
Total Consumables (excluding fuel)	3078.3	1.09

	10^3 $	
Fuel Cost (Increment) (First Year - Dec. 1985 dollars)	0.0	0.00 mills/kW-hr
Carrying Charges (First Year - Dec. 1985 dollars)	1320.1	2.64 $/kW-yr
Busbar Cost of Power (First Year - Dec. 1985 dollars)	4959.1	1.74 mills/kW-hr
First Year Cost Effectiveness SO_2 Removed	4959.1	603.24 $/ton
30-Year Levelized O&M Costs	10^3 $	
30-Year Levelized Fixed O&M	843.5	1.69 $/kW-yr
30-Year Levelized Variable O&M	454.0	0.16 mills/kW-hr
30-Year Levelized Consumables O&M	7123.2	2.50 mills/kW-hr
30-Year Levelized Carrying Charges	1320.1	2.64 $/kW-yr
30-Year Levelized Busbar Cost of Power at Levelized Capacity Factor (0.65)	9740.8	3.42 mills/kW-hr
30-Year Levelized Cost Effectiveness SO_2 Removed	9740.8	1184.91 $/ton

Note: (1) Coal Sulfur Content: 0.55 %
Calcium/Sulfur Mole Ratio: 3.5:1
SO_2 Removed in Boiler: 70 %
Overall SO_2 Removal: 70 %

TABLE 5: ECONOMIC ANALYSIS OF
500 MWE NEW LOW-SULFUR UNIT MODIFIED FOR
SORBENT INJECTION, WITH CAVITIES (WITH MILL)[1]

Capital Investment	10^3 $	$/kW
Process Capital	5050.5	10.10
General Facilities	252.5	0.50
Engineering and Home Office Fees	505.0	1.01
Project Contingency	1010.1	2.02
Process Contingency	505.0	1.01
Total Plant Cost (Dec. 1985 dollars)	7323.1	14.64
Total Plant Investment (Jan. 1986 startup)	7323.1	14.64
Preproduction Costs	2733.0	5.47
Inventory Capital	601.2	1.20
Total Capital Requirement (Jan. 1986 startup)	10657.3	21.31

Operating and Maintenance Costs (First Year - Dec. 1985 dollars)	10^3 $	$/kW-yr
Operating Labor	307.1	0.61
Maintenance Labor	80.8	0.16
Maintenance Materials	121.1	0.24
Administrative and Support Labor	116.4	0.23
Total O&M First Year	625.4	1.24
Fixed O&M First Year	406.5	0.81
Variable O&M First Year	218.9	0.08 mills/kW-hr

Consumables Operating Costs Excluding Fuel (First Year - Dec. 1985 dollars)	10^3 $	mills/kW-hr
Lime	2341.4	0.82
In-Plant Power (365.0 kW)	120.5	0.04
Other Consumables: Water	1.9	0.00
Waste Disposal	337.0	0.12
Total Consumables (excluding fuel)	2800.8	0.98

	10^3 $	
Fuel Cost (Increment) (First Year - Dec. 1985 dollars)	0.0	0.00 mills/kW-hr
Carrying Charges (First Year - Dec. 1985 dollars)	1631.6	3.26 $/kW-yr
Busbar Cost of Power (First Year - Dec. 1985 dollars)	5057.9	1.78 mills/kW-hr
First Year Cost Effectiveness SO_2 Removed	5057.9	615.27 $/ton
30-Year Levelized O&M Costs	**10^3 $**	
30-Year Levelized Fixed O&M	940.9	1.88 $/kW-yr
30-Year Levelized Variable O&M	506.5	0.18 mills/kW-hr
30-Year Levelized Consumables O&M	6481.0	2.28 mills/kW-hr
30-Year Levelized Carrying Charges	1631.6	3.26 $/kW-yr
30-Year Levelized Busbar Cost of Power at Levelized Capacity Factor (0.65)	9560.0	3.36 mills/kW-hr
30-Year Levelized Cost Effectiveness SO_2 Removed	9560.0	1162.92 $/ton

Note: (1) Coal Sulfur Content: 0.55 %
Calcium/Sulfur Mole Ratio: 3.1:1
SO_2 Removed in Boiler: 70 %
Overall SO_2 Removal: 70 %

TABLE 6: ECONOMIC ANALYSIS OF
500 MWE NEW LOW-SULFUR UNIT MODIFIED FOR
SORBENT INJECTION, NO CAVITIES (WITH MILL)[1]

Capital Investment	10^3 $	$/kW
Process Capital	4566.8	9.13
General Facilities	228.3	0.46
Engineering and Home Office Fees	456.7	0.91
Project Contingency	913.4	1.83
Process Contingency	456.7	0.91
Total Plant Cost (Dec. 1985 dollars)	6621.9	13.24
Total Plant Investment (Jan. 1986 startup)	6621.9	13.24
Preproduction Costs	2755.8	5.51
Inventory Capital	678.7	1.36
Total Capital Requirement (Jan. 1986 startup)	10056.4	20.11

Operating and Maintenance Costs (First Year - Dec. 1985 dollars)	10^3 $	$/kW-yr
Operating Labor	307.1	0.61
Maintenance Labor	73.1	0.15
Maintenance Materials	109.6	0.22
Administrative and Support Labor	114.0	0.23
Total O&M First Year	603.8	1.21
Fixed O&M First Year	392.5	0.78
Variable O&M First Year	211.3	0.07 mills/kW-hr

Consumables Operating Costs Excluding Fuel (First Year - Dec. 1985 dollars)	10^3 $	mills/kW-hr
Lime	2643.6	0.93
In-Plant Power (365.0 kW)	120.5	0.04
Other Consumables: Water	2.1	0.00
Waste Disposal	386.2	0.14
Total Consumables (excluding fuel)	3152.4	1.11

	10^3 $	
Fuel Cost (Increment) (First Year - Dec. 1985 dollars)	0.0	0.00 mills/kW-hr
Carrying Charges (First Year - Dec. 1985 dollars)	1539.6	3.08 $/kW-yr
Busbar Cost of Power (First Year - Dec. 1985 dollars)	5295.9	1.86 mills/kW-hr
First Year Cost Effectiveness SO_2 Removed	5295.9	644.22 $/ton

30-Year Levelized O&M Costs	10^3 $	
30-Year Levelized Fixed O&M	908.2	1.82 $/kW-yr
30-Year Levelized Variable O&M	488.9	0.17 mills/kW-hr
30-Year Levelized Consumables O&M	7294.6	2.56 mills/kW-hr
30-Year Levelized Carrying Charges	1539.6	3.08 $/kW-yr
30-Year Levelized Busbar Cost of Power at Levelized Capacity Factor (0.65)	10231.4	3.59 mills/kW-hr
30-Year Levelized Cost Effectiveness SO_2 Removed	10231.4	1244.59 $/ton

Note: (1) Coal Sulfur Content: 0.55 %
Calcium/Sulfur Mole Ratio: 3.5:1
SO_2 Removed in Boiler: 70 %
Overall SO_2 Removal: 70 %

TABLE 7: IN-PLANT INCREMENTAL POWER REQUIREMENTS FOR NEW 500 MWe LOW-SULFUR UNITS MODIFIED TO ACHIEVE 70% SO_2 REMOVAL (KW)

UNIT	UNLOADING/ TRANSPORT	HYDRATING	SORBENT PREP./INJ.	ASH HANDLING	TOTAL KW	% OF RATING
Without Mill	66.7	28.3	41.0	4.5	140.5	0.03
With Mill	66.7	28.3	265.5	4.5	365.0	0.07

TABLE 8: SORBENT INJECTION PROCESS CAPITAL COST BREAKDOWN

(DECEMBER, 1985 DOLLARS)

(10^3 $)

UNIT	SORBENT PREPARATION/ INJECTION	BOILER MODIFICATION	BACK-END EQUIPMENT	TOTAL
Without Mill				
With Cavities	2225.6	1757.7	106.6	4089.9
Without Cavities	2278.1	1231.2	96.9	3606.2
With Mill				
With Cavities	3186.2	1757.7	106.6	5050.5
Without Cavities	3238.7	1231.2	96.9	4566.8

TABLE 9: SORBENT INJECTION PROCESS CAPITAL COST BREAKDOWN
FOR SORBENT PREPARATION/INJECTION SYSTEM
NON-MILL-RELATED COSTS
(DECEMBER, 1985 DOLLARS)
(10^3 $)

UNIT	UNLOADING	HYDRATING	PIPING	FANS	VALVES	BIN	STRUCTURAL STEEL	ENCLOSURE	CONTROLS	TOTAL
With Cavities	915.3	294.3	130.7	39.2	13.4	44.9	215.4	280.8	291.6	2225.6
Without Cavities	915.3	294.3	183.2	39.2	13.4	44.9	215.4	280.8	291.6	2278.1

TABLE 10: SORBENT INJECTION PROCESS CAPITAL COST BREAKDOWN
FOR SORBENT PREPARATION/INJECTION SYSTEM
MILL-RELATED COSTS
(DECEMBER, 1985 DOLLARS)
(10^3 $)

UNIT	MILL	MOTORS	FEEDER	STRUCTURAL STEEL	ENCLOSURES	MILL-RELATED TOTAL
With or Without Cavities	656.6	28.5	84.9	147.4	43.2	960.6

TABLE 11: SORBENT INJECTION PROCESS CAPITAL COST BREAKDOWN FOR BOILER MODIFICATIONS (DECEMBER, 1985 DOLLARS) (10^3 $)

UNIT	SURFACE MODIFICATIONS	INCREASED SOOTBLOWING CAPACITY	TOTAL
With Cavities	714.2	1043.5	1757.7
Without Cavities	187.7	1043.5	1231.2

REFERENCES

1. Clark, J. P., et al., "Boiler Design Criteria for Dry Sorbent SO_2 Control with Low-NO_x Burners," EPA 600/7-86-023, (NTIS Report No. PB 86-216736), July, 1986.

2. "Lime Hydration Systems," Bulletin HYD, Kennedy van Saun Corporation, Danville, PA, October, 1983.

CONVERSION UNITS

To convert from	to	Multiply by
tons	tonnes	0.9072
in.	m	0.00254
ft	m	0.3048
Btu/lb	J/kg	0.002324
ft^2	m^2	0.09290

$$t°C = (t°F - 32)/1.8$$

GLOSSARY

Term	Description
assys.	Assemblies: groupings of tubes which are essentially coplanar.
devel. ft^2	Developed surface area: total circumferential surface area of gas-touched tubes.
elem.	Element: a tube within an assembly.
lin.ft.	Lineal feet: total running length of gas-touched tube material.
loop	A U-shaped portion of an element.
projected ft^2	Projected surface area: length x width x 2 for panels and platens.
S_L	Longitudinal tube spacing (in direction of gas flow), inches.
S_T	Transverse tube spacing (perpendicular to gas flow), inches.